Mature Based for New Solutions Conference

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Joint Stimulation-Water Shut-off Technologies Lead to Extra Oil from Mature Fields

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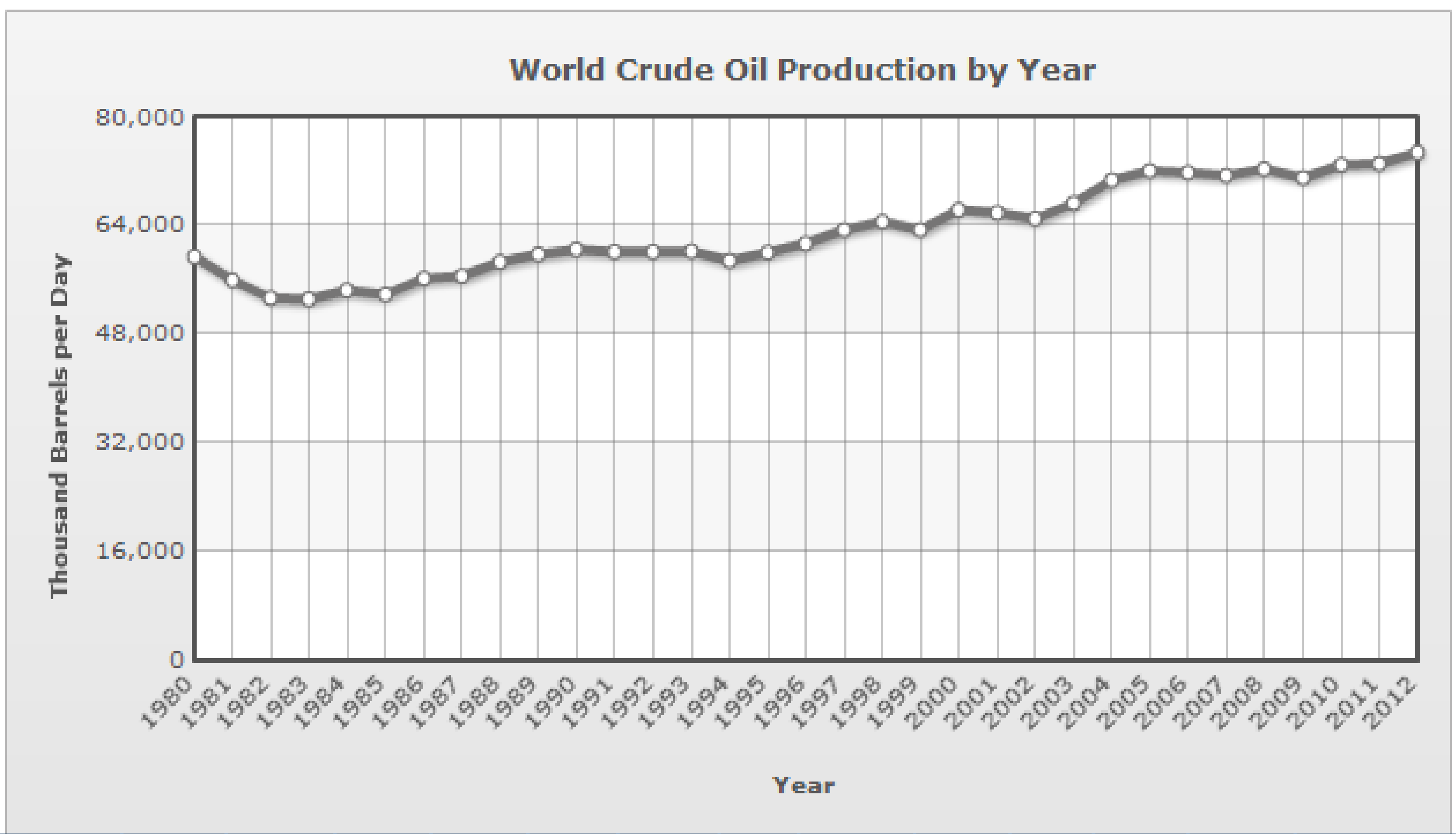
Background

2012: World Yearly Oil Production ≈ 74.65 MMbbl/d,
75 % Water cut,
60 % production from brown field w ≥ 80 % Water cut (non-OPEC)



What is the present global problem?

- There is a wide gap between forecasted production & demand
- Global demand will average 92 Million bbl/d in 2014 @115 $/bbl
- In the past decades the incremental contribution of exploration to reserves is less than the annual production.

Historical Crude Oil Prices

Year	Dollars	Year	Dollars	Year	Dollars	Year	Dollars
1946	1.4	1966	2.9	1986	15	2006	66
1947	1.8	1967	3.0	1987	19	2007	72
1948	2.6	1968	3.1	1988	16	2008	100
1949	2.6	1969	3.3	1989	20	2009	62
1950	2.6	1970	3.4	1990	24	2010	79
1951	2.6	1971	3.6	1991	21	2011	95
1952	2.6	1972	3.6	1992	21	2012	94
1953	2.7	1973	3.9	1993	18		
1954	2.8	1974	10	1994	17		
1955	2.8	1975	11	1995	18		
1956	2.8	1976	13	1996	22		
1957	3.0	1977	14	1997	21		
1958	3.1	1978	15	1998	14		
1959	3.0	1979	22	1999	19		
1960	3.0	1980	37	2000	30		
1961	3.0	1981	37	2001	26		
1962	3.0	1982	34	2002	26		
1963	3.0	1983	30	2003	31		
1964	2.9	1984	29	2004	41		
1965	2.9	1985	28	2005	56		

Average Crude Oil Prices are shown in this table: 1946 to present

What our answer can be ?

Oilfield Chemistry

(Multidisciplinary branch of sciences integrating the knowledge of reservoir engineering, production engineering, chemical engineering, chemistry & many more…)

Mission of Oilfield Chemistry:

- ***To increase the recovery efficiency up to a possible ultimate limit***
- ***To maintain the production at matured, depleted oil fields.***

Declarations - Definitions

1st

❑Water is an unwanted by-product of petroleum production and as such should be immobilized in situ. (Is water always detrimental to petroleum production ?)

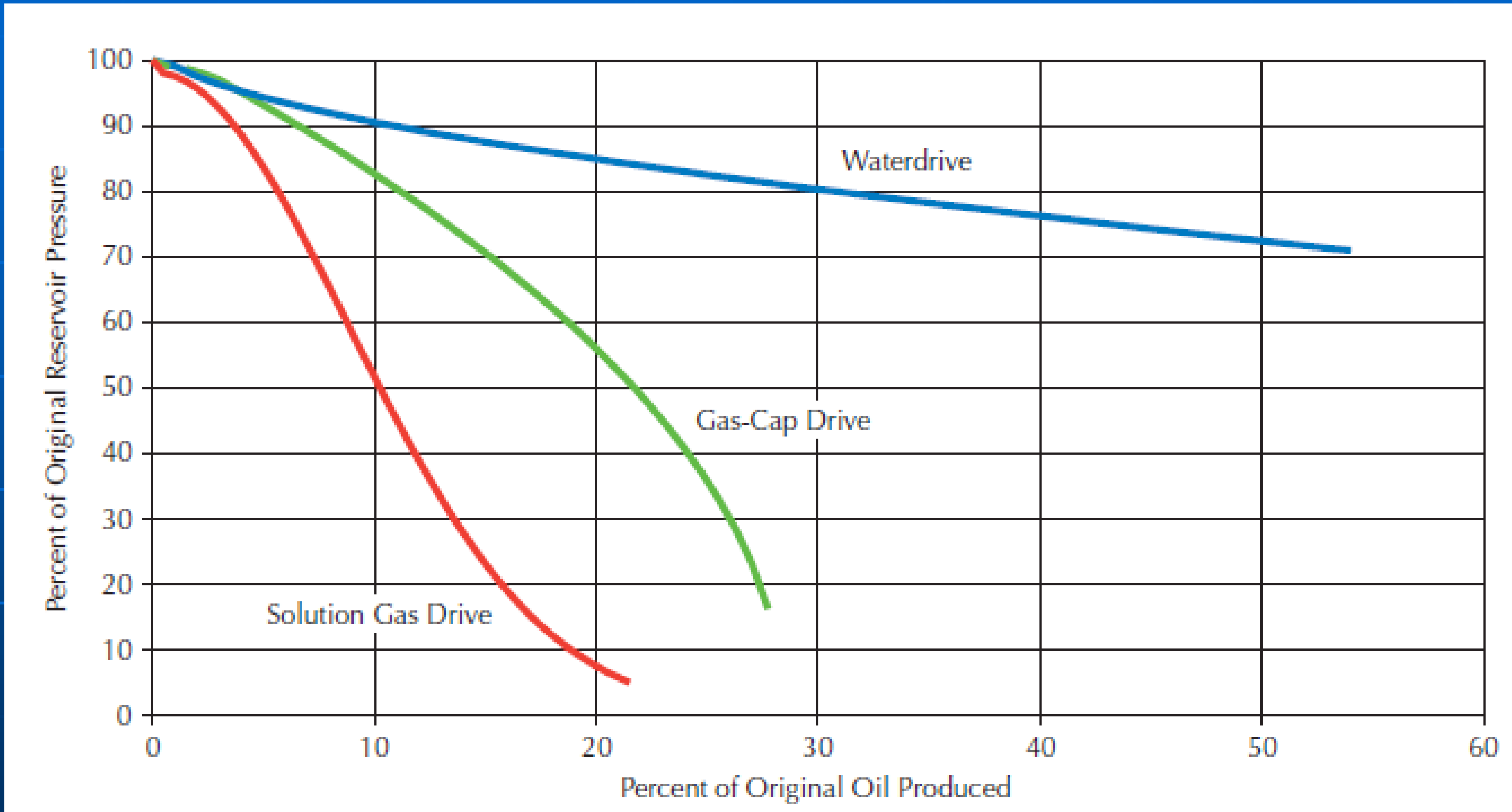
2nd

Water Shut-off:

❑Stopping water flow in the reservoir (chemical shut-off)

❑Arresting inflow of water to the well (mechanical shut-off)

Bad or Good Water?



In oil reservoirs, natural water drive gives the highest recovery

Bad or Good Water?

In the Reservoirs:

❑Water invasion to oil reservoirs is *useful* as it provides drive, recovery, and pressure maintenance
❑Water flow in oil reservoir could be also *detrimental* (oil by-passing, low ultimate recovery)
❑Water invasion to gas reservoirs is *detrimental* (low recovery)

In the Wells:

❑Water inflow to petroleum wells is always harmful:
- reduces production rate of oil or gas
- causes early shut downs
- leaves un-recovered oil outside the wells

WHY DO WE WANT TO REDUCE WATER PRODUCTION?

REDUCE OPERATING EXPENSES

- Reduce pumping costs (lifting and re-injection):
  ~$0.25/bbl ($0.01 to $8/bbl range)
- Reduce oil/water separation costs
- Reduce platform size/equipment costs
- Reduce corrosion, scale, and sand-production treatment costs
- Reduce environmental damage/liability

INCREASE HYDROCARBON PRODUCTION

- Increase oil production rate by reducing fluid levels and downhole pressures.
- Improve reservoir sweep efficiency.
- Increase economic life of the reservoir and ultimate recovery.
- Reduce formation damage.

Definition of Success in Matrix Stimulation

" We define a matrix stimulation job as success when the technical and economic objectives are reached . It is a failure if those goals are not reached." (Paccaloni 1993)

"Acidizing is successful only if two conditions are met : the skin damage in the well is reduced or removed, enabling the well to flow at higher rates at the same or lower drawdown, and the actual rate produced by the well increased sufficiently to pay out the job in a reasonable period of time ."
(SPE 14827 1987)

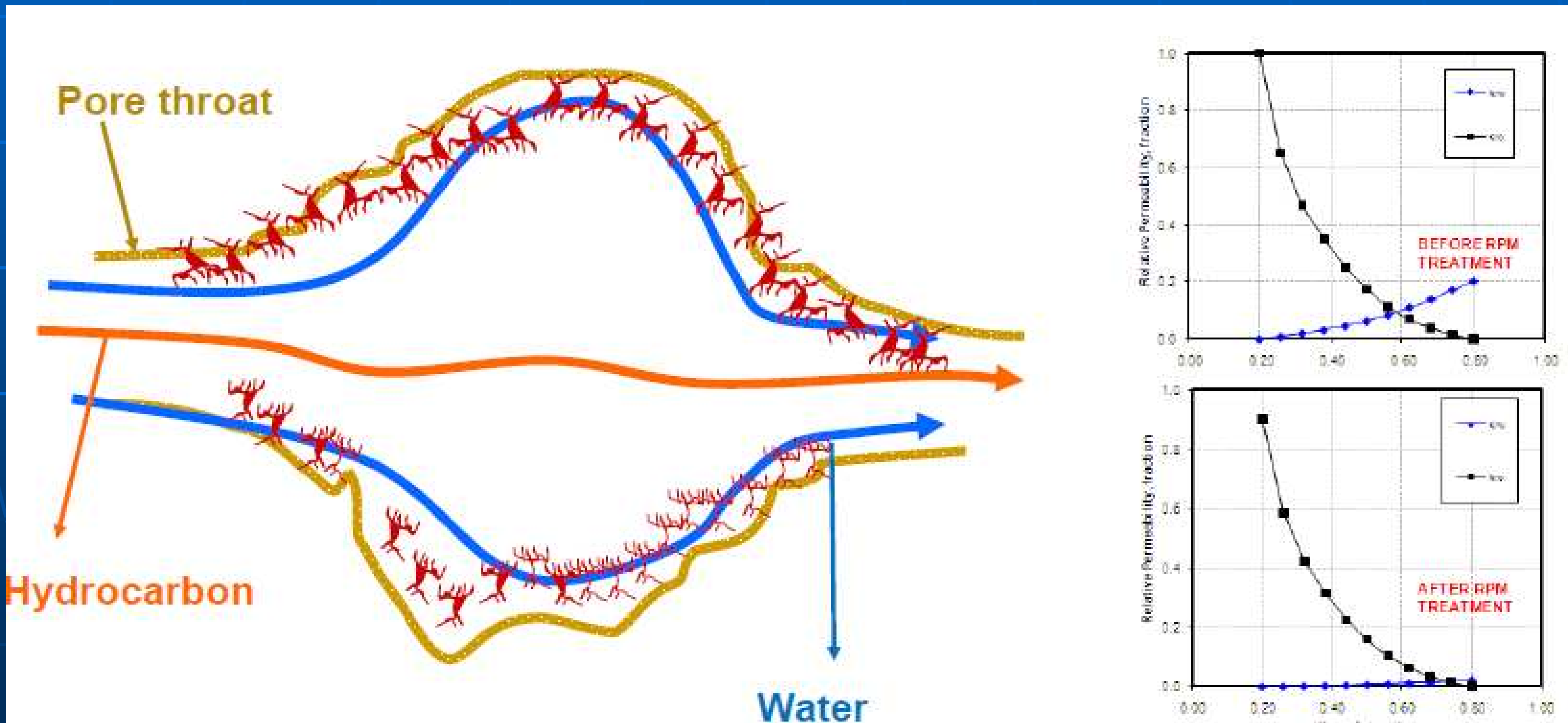
2 Reasons Why Acid Treatments Fail:

- ❑ **Acid-removable damage is not present**
- ❑ **If it is present it is not fully contacted**
  (Acid does not go where it needs to go)

Relative Permeability Modification

Certain water-soluble polymers, inorganic gels show different behaviour (resistance) against the oil and water flow

($k_{r,o} = k_o/k \quad 0 < k_{r,o} < 1$)



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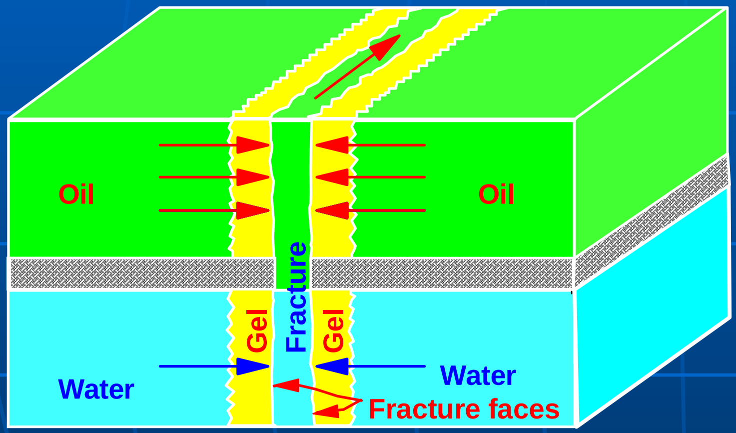
$$(k_{r,o} = k_o/k \qquad 0< k_{r,o} <1)$$

RRF to oil can be expressed as: $RRF_o = \dfrac{k_{r,o,before}\,(S_{wr})}{k_{r,o,after}\,(S_{wr})}$

Year	SPE Paper No.	Rock Type	Rock Permeability	RRF□	RRFw
2011	140845	Sandstone	Medium	1.05	37.5
2010	125955	Sandstone	Low	Gas	1.4
2009	123869	Sandstone	High	1.06	1684
2009	121789	Sandstone	Medium	0.95	56.7
2009	119850	Sandstone	Low	1.1-1.8	1.1-3.6
2008	114557	Sandstone	Very Low	Gas	1.5
		Limestone	Very Low	Gas	1.2
2008	112458	Carbonate	Low	2	7.8
2007	106951	Carbonate	Low	2	6.1
2005	89413	Sandstone	Low	1.5	20
		Sandstone	High	-	102-108-227

Relative Permeability Modification

- RPM systems have their greatest potential in treating fractures (R.S. Seright: SPE 99443)



Equivalent resistance to flow added by the AP polymer (expressed as distance through untreated rock):

In oil zone: 0.1 ft x 2.0 = 0.2 ft.
In water zone: 0.1 ft x 7.8 = 0.78 ft.
In water zone: 0.1 ft x 6.1 = 0.61 ft.

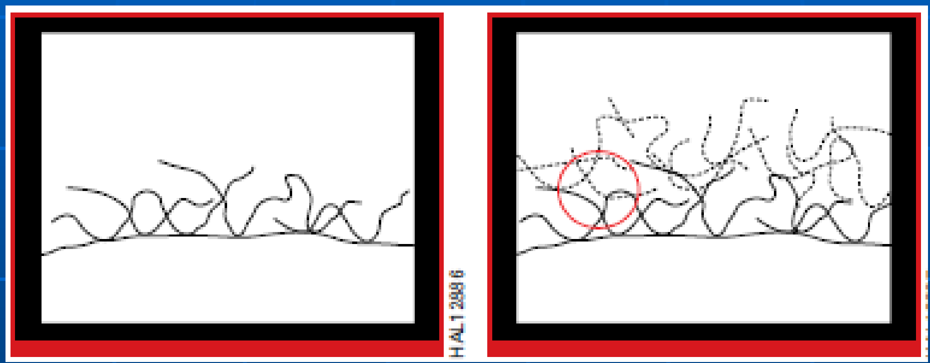
Hydrophobically Modified Associative Polymer

- Acrilamyde type polymer (water soluble, hydrophilic), modified with linear (hydrophobic) acrylate chain (C-18)>
- Primarily cationic at pH below 7, and anionic at pH above 7.
- Hydrophobic chains show associative tendency, polymer network (micellar gel) consist of intra- & inter-molecular hydrophobic junctions (depicted as transient X-link).
- Rheology of polymer solutions: Newtonian behavior at low shear rates; shear thickening followed by shear thinning behavior at high deformation rate.
- As the shear force increases the content of loop-like chains decreases while the fraction of bridge-like chains rises.

Polymer Adsorption

Expected polymer adsorption and association (SPE 89413)

The layer of generic water soluble polymer that builds up, polymer chains are adsorbed directly onto the surface of the rock.
Some entanglement leads to polymer chains not adsorbed directly to the surface but the thickness of the layer is limited. (left)



Adsorption of the hydrophobically modified polymer (hydrophobic groups attached).
The same arrangement exists as on the previous one, but a layer of polymer chains has adsorbed onto that first layer. These are the polymers represented by the dashed lines, and they are "stuck" to the first layer by the hydrophobic associations. The red circle represents the interaction between the first layer adsorbed onto the surface and the next layer adsorbed due to the hydrophobic associations.

Polymer Adsorption

- Polymer adsorption is immediate on the rock surface.
- Mechanism is still not clear.
- The polymer attaches to the rock surface electrostaticly, a + charged polymer attaches to the - charged rock surface.
- Limited info about the application for carbonates.
- Depends on: Chemistry: polymer, surface, polymer adsorption,
  Lithology: mineralogy, heterogenity,
  Reservoir characteristics: perm., natural fractures, pore throat radius/ fracture width or conductivity)
  Oil saturation
  Wettability
- Difficult to determine the required vol. for fractured systems.
- The supplier's calculation is valid for matrix case only.
- The calculation based on porosity and penetration distance only.
- The lab resistance factors sometimes are misleading, not reliable. (S_w & S_{ro})

WHAT DIAGNOSTIC TOOLS SHOULD BE USED?

1. Production history, WOR values, GOR values
2. Pattern recovery factors, zonal recovery factors
3. Pattern throughput values (bubble maps)
4. Injection profiles, production profiles
5. Zonal saturation determinations (from logs, cores, etc.)
6. Injectivities, productivites (rate/pressure), step rate tests
7. Casing/tubing integrity tests (leak tests)
8. Temperature surveys, noise logs
9. Cement bond logs
10. Televiewers, FMI logs
11. Interwell transit times, water/hydrocarbon composition
12. Mud losses & bit drops while drilling
13. Workover & stimulation responses, previous treatments
14. Pressure transient analysis, Inter-zone pressure tests
15. Geological analysis, seismic methods, tilt meters
16. Simulation, numerical, analytical methods
17. Other

Candidate Selection Guideline

The following parameters should be carefully studied during candidate selection:

- **Estimated remaining reserve, current water/oil saturation, available logs (RDL, FMI, CBL, RST, PLT)**
- **Production history, current gross production, water cut, drawdown pressure,**
- **Time of water breakthrough, water cut development, changes,**
- **Presence and intensity of natural fractures, breakouts,**
- **Permeability range, matrix permeability, reservoir section thickness (net/gross) in the given well.**

- **Radial (matrix) flow or Linear (fracture-like) flow expected:**

$$q/\Delta p \leq (\Sigma\, k\, h)/[141.2\, \mu\, \ln\, (r_e\, /\, r_w)]$$

$$q/\Delta p >> (\Sigma\, k\, h)/[141.2\, \mu\, \ln\, (r_e\, /\, r_w)]$$

All together 10 vertical and 23 horizontal wells have been selected.

Treatment Design

- **Acid Type: all** kind of acids or acid mixtures for deep penetration & minimized corrosion,

- **Placement techniques:**
  Bullhead injection
  Isolation with mechanical packer: RTTS and PPI
  Coiled Tubing application

- **Fluid diversion:**
  MAPDIR
  Dual injection
  AP polymer as chemical acid diverter
  Foam

- **Acid/Polymer ratio:**
  2:1 wells below 500 m^3/d gross
  1:1 if the well was not acid stimulated before &/or gross between 500-1000 m^3/d
  1:2+ if the water cut was near to 100% &/or 1000 m^3/d gross

Case History

Field A & B

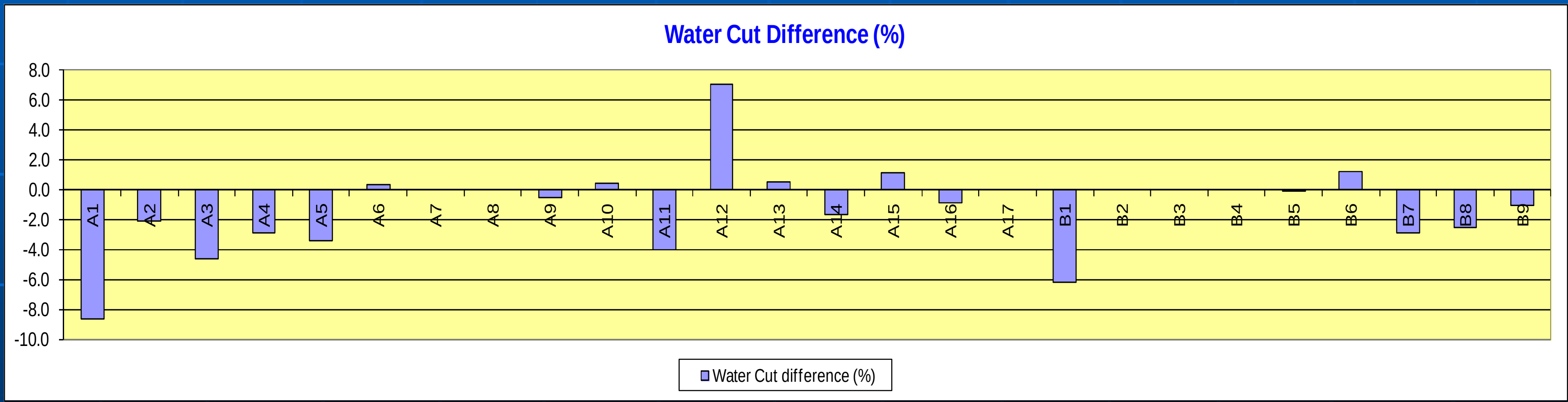
Discovered in 1969 (A) and 1962
Reservoir:
complex carbonate reservoir
porosity: 14% – 35% (A) & 27% - 35%
Matrix permeability : <1 mD to >1000 mD (A)
<1 mD to >200 mD
P_i = 17,160 -> 12,500 kPa (A)
15,600 -> 14,400 kPa
T_r = 81 deg C
38° API (A) and 40.3° API oil
Peak net-oil rate: 1973 (A) and 1997

Water cut was developing gradually to 70%. Thereafter, the field performance started to decline with increasing water-cut and declining reservoir pressure.

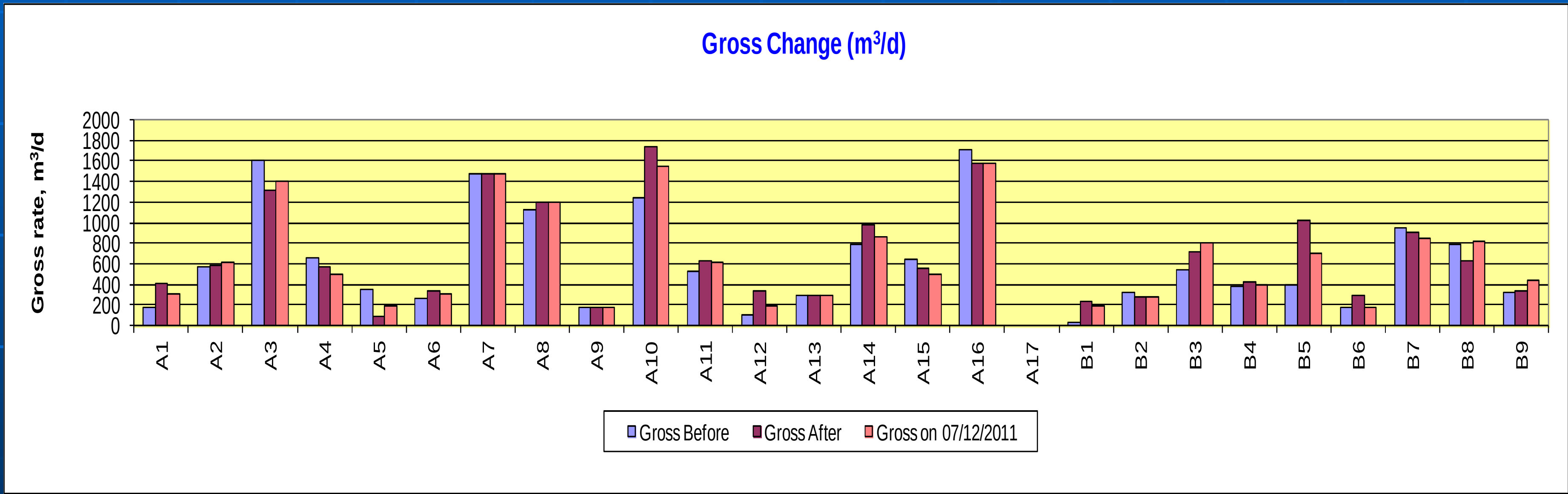
Oil Gains and Sustainability

Well Name	Oil Gain after activity (m³/d)	Max Oil Gain (m³/d)	Oil Gain (6/12/2011) (m³/d)	Time to Reach Peak Oil Gain (Months)	Sustainability(Months)
A1	15	44	0	3.6	39.7
A2	10	14	0	2.6	34.2
A3	59	68	17	12.9	30.3
A4	11	14	10	4.8	8.1
A5	-5	0	0	0	0
A6	-2	2	0	12.4	18.0
A7	2	2	2	1.0	1.0
A8	1	1	1	1.0	1.0
A9	0	1	0	5.5	5.5
A10	6	6	1	1.4	11.4
A11	20	27	15	2.3	11.3
A12	18	18	2	0.6	13.0
A13	-2	0	0	0	0
A14	14	17	19	2.0	7.5
A15	-7	0	0	0	0
A16	13	13	13	1.8	1.8
A17	0	0	0	0	0
B1	24	30	18	11.6	23.3
B2	-6	0	0	0	0
B3	1	4	4	3.5	3.5
B4	2	2	2	1.6	1.7
B5	9	15	0	13.2	27.7
B6	1	2	1	3.9	11.8
B7	25	25	13	0.2	10.8
B8	14	14	0	0.8	8.3
B9	4	4	7	0.8	8.5

Water Cut Differences After the Treatments



Gross Changes After the Treatments



Summary of Results (SPE 149658)

Performance Data	A Field	B Field
# Wells Stimulated	17	16 (9 open)
Average Oil Gain (m^3/d)	226	96
Cumulative Oil Gain (m^3)	105,270	77,730
Water Cut (%)	-1.4	-1.9
	(cum.-19.3%)	(cum.-11.5%)
	> 100 000 m^3 water reduced	

Thank You

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Chemical Structure of Hydrophobically Modified, Associative Polymer